CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
YEAR ENDED DECEMBER 31, 2016

FINANCIAL & OPERATING HIGHLIGHTS

(in United States dollars (tabular amounts in thousands) except as otherwise noted)

Financial	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve Months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Petroleum and natural gas revenues, net of royalties	**41,967**	17,402	141%	**147,985**	39,360	276%	149,047	(1%)
Adjusted petroleum and natural gas revenues, net of royalties[2]	**47,943**	24,883	93%	**173,184**	54,782	216%	177,937	(3%)
Cash provided by operating activities	**30,289**	4,974	509%	**73,577**	19,276	282%	64,445	14%
Per share – basic ($)	**0.17**	0.03	467%	**0.44**	0.14	214%	0.58	(24%)
Per share – diluted ($)	**0.17**	0.03	467%	**0.44**	0.13	238%	0.58	(24%)
Adjusted funds from operations [1] [2]	**41,979**	8,473	395%	**113,019**	23,690	377%	87,395	29%
Per share – basic ($)	**0.24**	0.05	380%	**0.68**	0.17	300%	0.79	(14%)
Per share –diluted ($)	**0.24**	0.05	380%	**0.67**	0.16	319%	0.78	(14%)
Comprehensive income (loss)	**20,331**	(84,466)	n/a	**23,638**	(103,495)	n/a	(106,022)	n/a
Per share – basic ($)	**0.12**	(0.54)	n/a	**0.14**	(0.72)	n/a	(0.96)	n/a
Per share – diluted ($)	**0.12**	(0.54)	n/a	**0.14**	(0.72)	n/a	(0.96)	n/a
Capital expenditures, net, including acquisitions	**58,638**	22,394	162%	**107,930**	44,693	141%	217,342	(50%)
Adjusted capital expenditures, net, including acquisitions [1][2]	**59,691**	22,867	161%	**110,224**	48,947	125%	243,108	(55%)
				December 31, 2016	December 31, 2015			
Cash				**66,283**	43,257	53%		
Restricted cash				**62,073**	61,721	1%		
Working capital surplus, excluding non-cash items and current portion of bank debt[1]				**64,899**	46,310	40%		
Current and long-term bank debt				**250,638**	248,228	1%		
Total assets				**787,508**	668,349	18%		
Common shares, end of period (000s)				**174,359**	159,266	9%		

Operating	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Petroleum and natural gas **production**, before royalties (boepd)								
Petroleum [2]	**3,616**	5,523	(35%)	**4,012**	6,253	(36%)	7,999	(50%)
Natural gas	**14,112**	3,541	299%	**11,930**	3,507	240%	3,505	240%
Total [2]	**17,728**	9,064	96%	**15,942**	9,760	63%	11,504	39%
Petroleum and natural gas **sales**, before royalties (boepd)								
Petroleum [2]	**3,657**	5,468	(33%)	**4,019**	6,370	(37%)	8,010	(50%)
Natural gas	**13,986**	3,542	295%	**11,830**	3,499	238%	3,512	237%
Total [2]	**17,643**	9,010	96%	**15,849**	9,869	61%	11,522	38%
Realized contractual sales, before royalties (boepd)								
Natural gas	**14,653**	3,891	277%	**12,357**	3,674	236%	3,512	252%
Crude oil	**2,026**	3,390	(40%)	**2,315**	4,253	(46%)	6,083	(62%)
Ecuador (tariff oil) [2]	**1,631**	2,078	(22%)	**1,704**	2,117	(20%)	1,927	(12%)
Total [2]	**18,310**	9,359	96%	**16,376**	10,044	63%	11,522	42%
Operating netbacks ($/boe) [1]								
Esperanza (natural gas)	**26.35**	24.03	10%	**27.15**	23.27	17%	20.62	32%
VIM-5 (natural gas)	**21.99**	20.78	6%	**23.68**	20.78	14%	-	n/a
LLA-23 (oil)	**14.80**	12.02	23%	**12.05**	16.74	(28%)	34.91	(65%)
Ecuador (tariff oil) [2]	**38.54**	38.54	-	**38.54**	38.54	-	38.54	-
Total [2]	**24.00**	21.96	9%	**24.92**	22.38	11%	28.05	(11%)

(1) Non-IFRS measure – see "Non-IFRS Measures" section within MD&A.
(2) Inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section within MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. and its subsidiaries ("Canacol" or the "Corporation") are primarily engaged in petroleum and natural gas exploration and development activities in Colombia, Ecuador and Mexico. The Corporation's head office is located at 4500, 525 - 8th Avenue SW, Calgary, Alberta, T2P 1G1, Canada. The Corporation's shares are traded on the Toronto Stock Exchange under the symbol CNE, the OTCQX in the United States of America under the symbol CNNEF, the Bolsa de Valores de Colombia under the symbol CNEC and the Bolsa Mexicana de Valores under the symbol CNEN.

Advisories

The following management's discussion and analysis ("MD&A") is dated March 23, 2017 and is the Corporation's explanation of its financial performance for the year covered by its financial statements along with an analysis of the Corporation's financial position. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Corporation for the year ended December 31, 2016, six months ended December 31, 2015 and year ended June 30, 2015 (the "financial statements"). The financial year end of the Corporation was changed from June 30 to December 31 in the prior period in order to align the Corporation's year end with its peer group to allow for easier comparisons. Accordingly, the fiscal year-to-date comparative figures for the following MD&A are for the six months ended December 31, 2015 and twelve months ended June 30, 2015. The financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), and all amounts herein are expressed in United States dollars, unless otherwise noted, and all tabular amounts are expressed in thousands of United States dollars, except per share amounts or as otherwise noted. Additional information for the Corporation, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

Forward-Looking Statements – *Certain information set forth in this document contains forward-looking statements. All statements other than historical fact contained herein are forward-looking statements, including, without limitation, statements regarding the future financial position, business strategy, production rates, and plans and objectives of or involving the Corporation. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. In particular with respect to forward-looking comments in this MD&A, readers are cautioned that there can be no assurance that the Corporation will complete its planned capital projects on schedule or that petroleum and natural gas production will result from such capital projects, that additional natural gas sales contracts will be secured, that the Ecuadorian government will not renegotiate tariff prices on certain fixed priced contracts during low oil price environment, or that hydrocarbon-based royalties assessed will remain consistent or that royalties will continue to be applied on a sliding-scale basis as production increases on any one block. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom.*

In addition to historical information, this MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook"). These statements are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; fluctuations in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; and risks associated with oil and gas operations, many of which are beyond the control of the Corporation. Accordingly, there is no representation by the Corporation that actual results achieved during the forecast period will be the same in whole or in part as those forecasted. Except to the extent required by law, the Corporation assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are qualified in their entirety by these cautionary statements.

Readers are further cautioned not to place undue reliance on any forward-looking information or statements.

__Non-IFRS Measures –__ Due to the nature of the equity method of accounting the Corporation applies under IFRS 11 to its interest in the incremental production contract for the Libertador and Atacapi fields in Ecuador ("Ecuador IPC"), the Corporation does not record its proportionate share of revenues and expenditures as would be typical in oil and gas joint interest arrangements. Therefore, within this MD&A, management has provided supplemental measures of adjusted revenues and expenditures, which are inclusive of the Ecuador IPC, to supplement the IFRS disclosures of the Corporation's operations. Such supplemental measures should not be considered as an alternative to, or more meaningful than, the measures as determined in accordance with IFRS as an indicator of the Corporation's performance, and such measures may not be comparable to that reported by other companies.

One of the benchmarks the Corporation uses to evaluate its performance is adjusted funds from operations. Adjusted funds from operations is a measure not defined in IFRS. It represents cash provided by operating activities before changes in non-cash working capital, and includes the Corporation's proportionate interest of those items that would otherwise have contributed to funds from operations from the Ecuador IPC had it been accounted for under the proportionate consolidation method of accounting. The Corporation considers adjusted funds from operations a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Adjusted funds from operations should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation's determination of adjusted funds from operations may not be comparable to that reported by other companies. The Corporation also presents adjusted funds from operations per share, whereby per share amounts are calculated using weighted-average shares outstanding consistent with the calculation of net income (loss) and comprehensive income (loss) per share. The following table reconciles the Corporation's cash provided by operating activities to adjusted funds from operations:

	Three months ended December 31, 2016	Three months ended December 31, 2015	**Twelve months ended December 31, 2016**	Six months ended December 31, 2016	Twelve months Ended June 30, 2015
Cash provided by operating activities	**$ 30,289**	$ 4,974	**$ 73,577**	$ 19,276	64,445
Changes in non-cash working capital	**4,865**	(3,982)	**14,243**	(11,007)	(4,742)
Ecuador IPC revenue, net of current income tax	**6,825**	7,481	**25,199**	15,421	27,692
Adjusted funds from operations	**$ 41,979**	$ 8,473	**$ 113,019**	$ 23,690	87,395

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, excluding any non-cash items and the current portion of bank debt, and is used to evaluate the Corporation's financial leverage. Operating netback is a benchmark common in the oil and gas industry and is calculated as total petroleum and natural gas sales, less royalties, less production and transportation expenses, calculated on a per barrel of oil equivalent ("boe") basis of sales volumes using a conversion. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices.

Working capital and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet of natural gas to barrels of oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Ministry of Mines and Energy of Colombia.

RESULTS OF OPERATIONS

For the three months ended December 31, 2016, the Corporation's production primarily consisted of natural gas from its Nelson, Palmer, Clarinete and Oboe fields in the Lower Magdalena Basin in Colombia, crude oil from its Leono, Labrador, Pantro, Tigro and Maltes fields in the Llanos Basin in Colombia, tariff oil from the Ecuador IPC, and, to a lesser extent, crude oil from its Rancho Hermoso and Santa Isabel properties in Colombia and its Moloacan properties in Mexico.

The Nelson and Palmer fields at the Esperanza block and the Clarinete and Oboe fields at the VIM-5 block, located in the Lower Magdalena Basin in Colombia, produce dry natural gas for sale to local customers under long-term take-or-pay as well as short-term spot market contracts. The construction of the Promigas natural gas pipeline was completed on April 21, 2016, which allowed Canacol to increase gas production capacity by an additional 65 million standard cubic feet per day ("MMscfpd") (11,400 boe per day ("boepd")) from 25 MMscfpd (4,386 boepd) to 90 MMscfpd (15,789 boepd).

In September, 2016, the Corporation spud the Trombon-1 exploration well on its Esperanza block. The Trombon-1 exploration well reached total depth of 10,360 feet measured depth ("ft. md"). The well encountered 26 ft. md of net gas pay with average porosity of 22% within the primary Cienaga de Oro ("CDO") reservoir target. The CDO reservoir interval was perforated between 8,328 to 8,354 ft. md and flowed at a final stabilized rate of 26 MMscfpd (4,562 boepd) of dry gas with no water. The Corporation finished the completion of the Trombon-1 well for permanent production via the Nispero-to-Jobo flow line, which will be completed in the second quarter of 2017, and tied into the Corporation's operated Jobo production facility.

In October and November, 2016, the Nelson-6 exploration well and Nelson-8 development well were also spud on the Corporation's Esperanza block, respectively. The wells reached total depth of 6,400 ft. md and 10,985 ft. md, respectively. The wells encountered 41 ft. md and 163 ft. md of net gas pay with average porosity of 19% within the Porquero reservoir and CDO sandstone primary targets, respectively. The Porquero reservoir interval in Nelson-6 was perforated between 5,752 and 5,760 ft. md and 5,784 and 5,831 ft. md and flowed at a final stabilized rate of 23 MMscfpd (4,035 boepd) of dry gas with no water. The Nelson-8 well will be flow tested via the flowline to avoid flaring of the gas once the well has been tied into the flowline. Upon completion and flow testing of the wells, the Nelson-6 and Nelson-8 wells will be tied via flowlines to the Betania substation and placed for permanent production via the Corporation's operated Jobo production facility.

In November, 2016, the Corporation commenced operations to recomplete the Nelson-5 well. The Nelson-5 well, which has been producing from the CDO for the past two years, contains 103 ft. md of net gas pay with average porosity of 29% within the Porquero sandstone reservoir. The Porquero reservoir was perforated between 6,083 and 6,174 ft. md and flowed at a final stabilized rate of 13 MMscfpd (2,281 boepd) of dry gas with no water. In addition to the established play type involving the deeper CDO sandstones which are productive at the Corporation's Nelson, Palmer, Clarinete, Oboe, Trombon, and Nispero gas fields, the success of both the Nelson-6 discovery, and the production test result from the Porquero sandstone reservoir at Nelson-5, confirms the commerciality of a new exploration play type in the shallower Porquero sandstones across the Corporation's acreage position held at 100% working interest on the Esperanza, VIM 5, VIM 19 and VIM 21 blocks, which combined are 785,000 net acres in size.

In November, 2016, the Corporation spud the Clarinete-3 development well on its VIM-5 block which reached total depth of 9,280 ft. md. The Clarinete-3 well is located one kilometer directly west of the Clarinete-2ST well drilled in 2015. The Clarinete-3 well encountered 31 ft. md of net gas pay with average porosity of 22% within the primary CDO sandstone target. The CDO reservoir interval in Clarinete-3 was perforated between 7,404 and 8,585 ft. md and flowed at a final stabilized rate of 18 MMscfpd (3,158 boepd) of dry gas with no water. The well was tested directly into the existing Clarinete flowline. The Clarinete-3 well is on permanent production through the same flowline as the Clarinete-1, Clarinete-2ST, and Oboe-1 wells.

In November, 2016, the Corporation announced the execution of an agreement with Promigas S.A. ("Promigas") to expand the existing gas distribution network currently used by the Corporation to accommodate an additional 100 MMscfpd of new gas transportation and sales, bringing total Corporate gas production and sales up to 190 MMscfpd in 2018. The expansion project, which is fully funded by Promigas and commenced in November 2016, will consist of up to 18 months of permitting followed by six months of construction, with first new gas delivery scheduled by December 2018. The project will include twinning of the existing Jobo-to-Sincelejo gas pipeline, the installation of additional compression on the existing Sincelejo-to-Cartagena pipeline, and the construction of a new gas pipeline between Cartagena and Barranquilla. These works will result in an additional 100 MMscfpd of capacity between the Corporation's gas processing facility at Jobo and Cartagena, and 50 MMscfpd of new transportation capacity between Cartagena and Barranquilla. The Corporation has negotiated four new take-or-pay gas sales contracts totalling 100 MMscfpd with existing and new thermoelectric, refining, industrial, and commercial customers located in Cartagena and Baranquilla. The contracts all commence in December 2018, have a term of between five and ten years, and are with large, established offtakers. The pricing of these new contracts, combined with the Corporation's current multi-year take-or-pay gas contracts, and the private pipeline sales as described below, results in an average contract price of approximately $5.00/Mcf for the anticipated 230 MMscfpd of production in December 2018.

A Special Purpose Vehicle ("SPV") has been formed to build a new private gas pipeline connecting the Corporation's gas facility located at Jobo to the Promigas operated pipeline at Sincelejo. The private pipeline will consist of approximately 80 kilometers of flowlines and two compression stations, and is designed to transport 40 MMscfpd of Canacol's gas to new and existing customers located in Cartagena under take-or-pay contracts at existing prices. Surveying and permitting for the new pipeline is underway, with first gas transportation anticipated in December 2017. The SPV is anticipated to raise approximately $60 million in a combination of equity and debt, outside of Canacol, to construct and operate the pipeline.

In December, 2016, the Corporation spud the Mono Capuchino-1 exploration well on its VMM-2 block. The Mono Capuchino-1 well is targeting light oil bearing reservoirs within the Cretaceous La Luna Formation and the tertiary Lisama formation.

The Corporation, through a consortium, participates in an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation is entitled to a tariff price of $38.54/bbl for each incremental barrel of oil produced over a pre-determined production base curve. Such incremental production volumes are reported as production in this MD&A. As further described above, as required under IFRS 11, the Ecuador IPC is being accounted for under the equity method of accounting. For purposes of this MD&A, management has provided supplemental measures for adjusted revenues and expenditures, which are inclusive of the Ecuador IPC, to supplement the IFRS disclosures of the Corporation's operations.

For the three months ended December 31, 2016, the Corporation also had crude oil production from its LLA-23, Rancho Hermoso and Santa Isabel properties in Colombia and its Moloacan properties in Mexico. The Corporation's Rancho Hermoso, Santa Isabel and Moloacan properties individually contributed only a minor amount to total production in the three months ended December 31, 2016 and, therefore, they were aggregated into a single group ("Other") for analysis purposes in this MD&A. These properties are susceptible to negative cash flows in a low oil price environment and the Corporation plans to shut-in any wells under its control that are uneconomic. As of the date of this MD&A, all wells at the Capella and VMM-2 fields have been shut-in.

In addition to its producing fields, the Corporation has interests in a number of exploration blocks in Colombia.

Average Daily Petroleum and Natural Gas Production and Sales Volumes

Production and sales volumes in this MD&A are reported before royalties.

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	**Twelve months ended December 31, 2016**	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Production (boepd)								
Esperanza (gas)	**8,168**	3,350	144%	**7,401**	3,411		3,505	111%
VIM-5 (gas)	**5,944**	191	>999%	**4,529**	96	>999%	-	n/a
LLA-23 (oil)	**1,290**	2,745	(53%)	**1,652**	3,429	(52%)	4,657	(65%)
Ecuador (tariff oil)	**1,631**	2,078	(22%)	**1,704**	2,117	(20%)	1,927	(12%)
Other (oil and liquids)	**695**	700	(1%)	**656**	707	(7%)	1,415	(54%)
Total production	**17,728**	9,064	96%	**15,942**	9,760	63%	11,504	39%
Inventory movements and other	**(85)**	(54)	57%	**(92)**	109	n/a	18	n/a
Total sales	**17,643**	9,010	96%	**15,850**	9,869	61%	11,522	38%
Sales (boepd)								
Esperanza (gas)	**8,051**	3,349	140%	**7,325**	3,402	115%	3,512	109%
VIM-5 (gas)	**5,935**	193	>999%	**4,505**	97	>999%	-	n/a
LLA-23 (oil)	**1,313**	2,745	(52%)	**1,651**	3,523	(53%)	4,668	(65%)
Ecuador (tariff oil)	**1,631**	2,078	(22%)	**1,704**	2,117	(20%)	1,927	(12%)
Other (oil and liquids)	**713**	645	11%	**664**	730	(9%)	1,415	(54%)
Total sales	**17,643**	9,010	96%	**15,849**	9,869	61%	11,522	38%
Realized contractual sales (boepd)								
Esperanza (gas)	**8,051**	3,349	140%	**7,325**	3,402	115%	3,512	109%
VIM-5 (gas)	**5,935**	193	>999%	**4,505**	97	>999%	-	n/a
Take-or-pay volumes	**667**	349	91%	**527**	175	201%	-	n/a
Total natural gas	**14,653**	3,891	277%	**12,357**	3,674	236%	3,512	252%
Crude oil	**2,026**	3,390	(40%)	**2,315**	4,253	(46%)	6,083	(62%)
Ecuador tariff oil	**1,631**	2,078	(22%)	**1,704**	2,117	(20%)	1,927	(12%)
Total realized contractual sales	**18,310**	9,359	96%	**16,376**	10,044	63%	11,522	42%

The overall increase in production volumes in the three months ended December 31, 2016 compared to the same period in 2015 and in the year ended December 31, 2016 compared to the six months ended December 31, 2015 and year end June 30, 2015 is primarily due to an increase in gas production in the Esperanza and VIM-5 blocks as a result of the additional sales related to the Promigas pipeline expansion, offset by production declines from the oil fields in Colombia and Ecuador.

Total Cash Sales

	Three months ended December 31, 2016		Three months ended December 31, 2015		Twelve months ended December 31, 2016		Six months ended December 31, 2015		Twelve months ended June 30, 2015	
	$	Boepd	$	Boepd	$	Boepd	$	Boepd	$	Boepd
Cash Sales										
Gas sales (1)	**39,196**	**13,986**	9,421	3,542	**136,354**	**11,830**	17,880	3,499	32,093	3,512
Take-or-pay income (2)	**1,966**	**667**	930	349	**6,080**	**527**	930	175	-	-
Total realized contractual gas sales	**41,162**	**14,653**	10,351	3,891	**142,434**	**12,357**	18,810	3,674	32,093	3,512
Undelivered gas nominations (settlements) (3)	**(275)**	**(85)**	(62)	(39)	**3,317**	**290**	129	29	(418)	(61)
Natural Gas cash sales	**40,887**	**14,568**	10,289	3,852	**145,751**	**12,647**	18,939	3,703	31,675	3,451
Crude oil sales	**7,524**	**2,026**	9,071	3,390	**27,495**	**2,315**	25,539	4,253	133,220	6,083
Ecuador tariff oil sales (1)	**5,783**	**1,631**	7,369	2,078	**24,029**	**1,704**	15,014	2,117	27,114	1,927
Total Cash sales	**54,194**	**18,225**	26,729	9,320	**197,275**	**16,666**	59,492	10,073	192,009	11,461

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

The Corporation has three types of natural gas sales, as reconciled in the above table:

1) *Natural Gas sales* - represents natural gas production less a typically small amount of gas volume that is consumed at the field level;
2) *Take-or-pay income* - represents the portion of natural gas sales nominations by the Corporation's off-takers that do not get delivered, typically due to the off-taker's inability to accept such gas and for which the off-takers have no recourse or legal right to delivery at a later date. As such, they are recorded as revenue in the period;
3) *Undelivered gas nominations* - represents the portion of undelivered natural gas sales nominations for which the off-takers do have a legal right to take delivery at a later date, for a fixed period of time ("make-up rights"). These nominations are paid for at the time, alongside gas sales and take-or-pay income, and as such are included in deferred income for the period. The Corporation recognizes revenues associated with such make-up rights ("settlements") at the earlier of: a) when the make-up volume is delivered; b) the make-up right expires; or c) when it is determined that the likelihood that the off-taker will utilize the make-up right is remote.

During the three months and year ended December 31, 2016, the Corporation realized $2 million and $6.1 million of take-or-pay income (as described in (2) above), respectively, which is equivalent to 667 boepd and 527 boepd of gas sales, respectively, without actual delivery of the natural gas.

During the three months ended December 31, 2016, certain off-takers were able to accept physical delivery of the "make-up rights" as described in (3) above. The net settlement in the quarter was $0.3 million. Gas cash sales for the three months ended December 31, 2016 were lower than its contractual nomination of 15,789 boepd (90 MMscfpd) primarily due to the customers' inability to accept their full nomination in the period.

As at December 31, 2016, 686,485 Mcf (120,436 boe) of gas nominations were paid and undelivered. The majority of the undelivered gas nominations are expected to be recognized as revenue upon delivery or expiry of the make-up rights in the next twelve months.

Petroleum and Natural Gas Revenues

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Esperanza	$ 22,762	$ 8,864	157%	$ 84,085	$ 17,323	385%	$ 32,093	162%
VIM-5	16,434	557	>999%	52,269	557	>999%	-	n/a
LLA-23	4,930	7,213	(32%)	19,440	20,672	(6%)	102,076	(81%)
Other	2,594	1,858	40%	8,055	4,867	66%	31,144	(74%)
Petroleum and natural gas revenues, before royalties	46,720	18,492	153%	163,849	43,419	277%	165,313	(1%)
Royalties	(6,719)	(2,020)	233%	(21,944)	(4,989)	340%	(16,266)	35%
Petroleum and natural gas revenues, after royalties	40,001	16,472	143%	141,905	38,430	269%	149,047	(5%)
Take-or-pay income	1,966	930	111%	6,080	930	554%	-	n/a
Petroleum and natural gas revenues, after royalties, as reported	41,967	17,402	141%	147,985	39,360	276%	149,047	(1%)
Ecuador tariff and other revenues	5,976	7,481	(20%)	25,199	15,422	63%	28,890	(13%)
Adjusted petroleum and natural gas revenues, after royalties [(1)]	$ 47,943	$ 24,883	93%	$ 173,184	$ 54,782	216%	$ 177,937	(3%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

The increase in adjusted petroleum and natural gas revenues, after royalties in the three months ended December 31, 2016 compared to the same period in 2015 is primarily the result of an increase in natural gas revenues due to additional sales related to the Promigas pipeline expansion, offset by lower crude oil sales in Colombia and Ecuador.

The increase in adjusted petroleum and natural gas revenues, after royalties in the year ended December 31, 2016 compared to the six months ended December 31, 2015 is due to the comparison being made between a twelve month period versus a six month period, in addition to an increase in natural gas revenues due to additional sales related to the Promigas pipeline expansion. The increase in adjusted petroleum and natural gas revenues, after royalties in the year ended December 31, 2016 compared and year ended June 30, 2015 is primarily the result of an increase in natural gas revenues due to additional sales related to the Promigas pipeline expansion, offset by lower realized average prices as a result of declines in benchmark crude oil prices and lower crude oil sales in Colombia and Ecuador.

Average Benchmark and Realized Sales Prices

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Brent ($/bbl)	$ 50.81	$ 43.56	17%	$ 44.45	$ 47.00	(5%)	$ 73.51	(40%)
West Texas Intermediate ($/bbl)	$ 50.19	$ 41.94	20%	$ 44.66	$ 44.31	1%	$ 69.46	(36%)
Natural gas ($/boe)	$ 30.46	$ 28.91	5%	$ 31.49	$ 27.78	13%	$ 25.04	26%
Crude oil ($/bbl)	40.37	29.08	39%	32.45	32.64	(1%)	60.01	(46%)
Ecuador tariff ($/bbl)	38.54	38.54	-	38.54	38.54	-	38.54	-
Esperanza ($/boe)	$ 30.73	$ 28.77	7%	$ 31.36	$ 27.67	13%	$ 25.04	25%
VIM-5 ($/boe)	30.10	31.37	(4%)	31.70	31.37	1%	-	n/a
LLA-23 ($/bbl)	40.82	28.56	43%	32.17	31.89	1%	59.91	(46%)
Ecuador ($/bbl)	38.54	38.54	-	38.54	38.54	-	38.54	-
Other($/bbl)	39.55	31.31	26%	33.15	36.23	(9%)	60.31	(45%)
Average realized sales price ($/boe) [(1)]	$ 32.35	$ 31.20	4%	$ 32.39	$ 32.18	1%	$ 45.76	(29%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

The increase in average realized natural gas sales prices in the three months ended December 31, 2016 compared to the same period in 2015 and the increase in average realized natural gas sales prices in the year ended December 31, 2016 compared to the six months ended December 31, 2015 and year ended June 30, 2015 are due to: a) the increase in the Guajira price in December 2015, from $5.08/MMbtu to $6.17/MMbtu, and b) the Corporation's fixed price gas sales contracts and intermittent sales of natural gas on the spot market at prices higher than the Guajira price during the three months and year ended December 31, 2016.

The increase in average realized crude oil sales prices in the three months ended December 31, 2016 compared to the same period in 2015 is mainly due to increase benchmark crude oil prices, coupled with lower discounts realized with certain customers. The average realized crude oil sales prices in the year ended December 31, 2016 is similar to the price for the six months ended December 31, 2015.

The decrease in average realized crude oil sales prices in the year ended December 31, 2016 compared to year ended June 30, 2015 is mainly due to decreased benchmark crude oil prices and increased delivery of crude oil at the well head, thereby reducing average realized crude oil sales prices as well as transportation expenses.

The tariff price for Ecuador tariff oil production is fixed at $38.54/bbl. During periods of low oil prices in 2015 and 2016, the Ecuador IPC (of which, Canacol owns 25%) did not receive the full $38.54/bbl in cash. The unreceived amounts recorded as receivables by the Ecuador IPC as at December 31, 2016 have since been received in the form of government of Ecuador interest bearing bonds.

Royalties

	Three months ended December 31, 2016	Three months ended December 31, 2015	**Twelve months ended December 31, 2016**	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Esperanza	**$ 1,886**	$ 736	**$ 7,315**	$ 1,382	$ 2,669
VIM-5	**3,543**	119	**11,288**	119	-
LLA-23	**518**	989	**2,133**	3,057	11,018
Other	**772**	176	**1,208**	431	2,579
Total royalties	**$ 6,719**	$ 2,020	**$ 21,944**	$ 4,989	$ 16,266

In Colombia, light crude oil and natural gas royalties are generally at a rate of 8% and 6.4%, respectively, until net field production reaches 5,000 boepd, at which time the royalty rates increase on a sliding scale to 20% up to field production of 125,000 boepd. The Corporation's LLA-23 and VMM-2 blocks are subject to an additional x-factor royalty of 3% (effectively 2.76%). Crude oil royalties in LLA-23 and VMM-2 are calculated from crude oil revenue net of transportation expenses. The Corporation's Capella heavy oil field is subject to a 6% royalty. Crude oil royalties in Labrador and Rancho Hermoso are taken in kind. There are no royalties on tariff production in Ecuador. The Corporation's Esperanza natural gas production is subject to an additional overriding royalty of 2% and the Corporation's VIM-5 natural gas production is subject to an additional x-factor royalty of 13% and an overriding royalty of 3% to 4%.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	**Twelve months ended December 31, 2016**	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Production expenses	**$ 6,123**	$ 4,906	25%	**$ 18,459**	$ 11,323	63%	$ 51,253	(64%)
Transportation expenses	**712**	727	(2%)	**2,917**	1,473	98%	6,961	(58%)
Total production and transportation expenses	**$ 6,835**	$ 5,633	21%	**$ 21,376**	$ 12,796	67%	$ 58,214	(63%)
$/boe	**$ 4.21**	$ 6.80	(38%)	**$ 3.69**	$ 7.05	(48%)	$ 13.84	(73%)

An analysis of production expenses is provided below:

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Esperanza	$ 1,356	$ 725	87%	$ 3,977	$ 1,372	190%	$ 3,004	32%
VIM-5	884	69	>999%	1,931	69	>999%	-	n/a
LLA-23	2,049	2,688	(24%)	7,892	5,663	39%	27,094	(71%)
Other	1,834	1,424	29%	4,659	4,219	10%	21,155	(78%)
Total production expenses	$ 6,123	$ 4,906	25%	$ 18,459	$ 11,323	63%	$ 51,253	(64%)
$/boe								
Esperanza	$ 1.83	$ 2.35	(22%)	$ 1.48	$ 2.19	(32%)	$ 2.34	(37%)
VIM-5	$ 1.62	$ 3.89	(58%)	$ 1.17	$ 3.89	(70%)	$ -	n/a
LLA-23	$ 16.96	$ 10.64	59%	$ 13.06	$ 8.74	49%	$ 15.90	(18%)
Total	$ 3.77	$ 5.92	(36%)	$ 3.18	$ 6.24	(49%)	$ 12.19	(74%)

Production expenses at Esperanza decreased 22% on a per boe basis in the three months ended December 31, 2016 compared to the same period in 2015. Production expenses at Esperanza decreased 32% and 37% on a per boe basis in the year ended December 31, 2016 compared to the six months ended December 31, 2015 and the year ended June 30, 2015, respectively. The decrease is due to the majority of the production expenses at Esperanza being fixed, thereby reducing production expenses per boe when production increases.

Production expenses at VIM-5 decreased 58% on a per boe basis in the three months ended December 31, 2016 compared to the same period in 2015. Production expenses at VIM-5 decreased 70% on a per boe basis in the year ended December 31, 2016 compared to the six months ended December 31, 2015. The decrease is due to the majority of the production expenses at VIM-5 being fixed, thereby reducing production expenses per boe when production increases.

The increase in gas production at Esperanza and VIM-5 is as a result of the additional sales related to the Promigas pipeline expansion completed in April, 2016, which allowed Canacol to increase gas production capacity by an additional 65 MMscfpd (11,400 boepd) from 25 MMscfpd (4,386 boepd) to 90 MMscfpd (15,789 boepd).

On a per barrel basis, production expenses at LLA-23 increased 59% in the three months ended December 31, 2016 compared to the same period in 2015 and 49% in the year ended December 31, 2016 compared to the six months ended December 31, 2015, despite the Corporation's cost-cutting initiatives of centralizing the production, loading, and water disposal operations from the different fields within the LLA-23 block to the Pointer facility, due to workovers such as pump changes, performed to halt base decline, which are profitable at current prices, as well as the allocation of fixed costs over lower production. On a per barrel basis, production expenses at LLA-23 decreased 18% in the year ended December 31, 2016 compared to the year ended June 30, 2016 mainly due to the Corporation's cost-cutting initiatives, lower renegotiated operating costs and the devaluation of the Colombian peso versus the United States dollar.

The Corporation does not pay production expenses in Ecuador, and as such, its tariff price of $38.54 equals its netback.

An analysis of transportation expenses is provided below:

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
LLA-23	$ 576	$ 499	15%	$ 2,136	$ 1,098	95%	$ 4,480	(52%)
Other	136	228	(40%)	781	375	108%	2,481	(69%)
Total transportation expenses	$ 712	$ 727	(2%)	$ 2,917	$ 1,473	98%	$ 6,961	(58%)
$/boe								
LLA-23	$ 4.77	$ 1.98	141%	$ 3.53	$ 1.69	109%	$ 2.63	34%
Total	$ 0.44	$ 0.88	(50%)	$ 0.50	$ 0.81	(38%)	$ 1.66	(70%)

Total transportation expenses have decreased by 2% in the three months ended December 31, 2016 compared to the same period in 2015 mainly due to lower crude oil production, offset by less oil production sold at the field in LLA-23. Total transportation expenses have increased by 98% in the year ended December 31, 2016 compared to the six months ended December 31, 2015. The increase is primarily due the comparison being made between a twelve month period versus a six month period. Total transportation expenses have decreased by 58% in the year ended December 31, 2016 as compared to the year ended June 30, 2015 mainly due to lower crude oil sales, increased delivery of crude oil at the well head and the devaluation of the Colombian peso versus the United States dollar.

The Corporation does not pay transportation costs at Esperanza or VIM-5 as gas pipeline costs are paid by the off-takers. The Corporation does not pay transportation costs in Ecuador.

Operating Netbacks

$/boe	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Petroleum and natural gas revenues	$ 32.35	$ 31.20	4%	$ 32.39	$ 32.18	1%	$ 45.76	(29%)
Royalties	(4.14)	(2.44)	70%	(3.78)	(2.75)	37%	(3.87)	(2%)
Production and transportation expenses	(4.21)	(6.80)	(38%)	(3.69)	(7.05)	(48%)	(13.84)	(73%)
Operating netback (1)	$ 24.00	$ 21.96	9%	$ 24.92	$ 22.38	11%	$ 28.05	(11%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

Operating netbacks by major production categories were as follows:

Natural Gas

$/boe	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Esperanza								
Natural gas revenues	$ 30.73	$ 28.77	7%	$ 31.36	$ 27.67	13%	$ 25.04	25%
Royalties	(2.55)	(2.39)	7%	(2.73)	(2.21)	24%	(2.08)	31%
Production expenses	(1.83)	(2.35)	(22%)	(1.48)	(2.19)	(32%)	(2.34)	(37%)
Operating netback	$ 26.35	$ 24.03	10%	$ 27.15	$ 23.27	17%	$ 20.62	32%
VIM-5								
Natural gas revenues	$ 30.10	$ 31.37	(4%)	$ 31.70	$ 31.37	1%	$ -	n/a
Royalties	(6.49)	(6.70)	(3%)	(6.85)	(6.70)	2%	-	n/a
Production expenses	(1.62)	(3.89)	(58%)	(1.17)	(3.89)	(70%)	-	n/a
Operating netback	$ 21.99	$ 20.78	6%	$ 23.68	$ 20.78	14%	$ -	n/a
Total Natural Gas								
Natural gas revenues	$ 30.46	28.91	5%	$ 31.49	$ 27.78	13%	$ 25.04	26%
Royalties	(4.22)	(2.62)	61%	(4.30)	(2.33)	85%	(2.08)	107%
Production expenses	(1.74)	(2.44)	(29%)	(1.36)	(2.24)	(39%)	(2.34)	(42%)
Operating netback	$ 24.50	23.85	3%	$ 25.83	$ 23.21	11%	$ 20.62	25%

Crude Oil

$/boe	Three months ended December 31, 2016		Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016		Six months ended December 31, 2015	Change		Twelve months ended June 30, 2015	Change
LLA-23											
Crude oil revenues	$ **40.82**	$	28.56	43%	$ **32.17**	$	31.89	1%	$	59.91	(46%)
Royalties	**(4.29)**		(3.92)	9%	**(3.53)**		(4.72)	(25%)		(6.47)	(45%)
Production and transportation expenses	**(21.73)**		(12.62)	72%	**(16.59)**		(10.43)	59%		(18.53)	(10%)
Operating netback	$ **14.80**	$	12.02	23%	$ **12.05**	$	16.74	(28%)	$	34.91	(66%)
Ecuador											
Tariff revenues (1)	$ **38.54**	$	38.54	-	$ **38.54**	$	38.54	-	$	38.54	-
Operating netback	$ **38.54**	$	38.54	-	$ **38.54**	$	38.54	-	$	38.54	-

(1) Revenues related to the Ecuador IPC are not included in Petroleum and Natural Gas Revenues as reported under IFRS – see "Non-IFRS Measures" section above.

General and Administrative Expenses

	Three months ended December 31, 2016		Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016		Six months ended December 31, 2015	Change		Twelve months ended June 30, 2015	Change
Gross costs	$ **10,466**	$	9,570	9%	$ **25,491**	$	15,240	67%	$	28,259	(10%)
Less: capitalized amounts	**(1,639)**		(945)	73%	**(3,931)**		(1,765)	123%		(4,209)	(7%)
General and administrative expenses	$ **8,827**	$	8,625	2%	$ **21,560**	$	13,475	60%	$	24,050	(10%)
$/boe	$ **5.44**	$	10.41	(48%)	$ **3.72**	$	7.42	(50%)	$	5.72	(35%)

Gross general and administrative expenses ("G&A") increased by 9% in the three months ended December 31, 2016 compared to the same period in 2015, due to increased staffing costs supporting incremental activities. G&A increased by 67% in the year ended December 31, 2016 compared to the six months period ended December 31, 2015 due to the comparison being made between a twelve month period versus a six month period. G&A decreased by 10% in the year ended December 31, 2016 compared to the year ended June 30, 2015 due to extensive reviews undertaken in 2016 with a focus on G&A reduction. Accrued annual bonuses and other year end accruals were included in G&A for the three months ended December 31, 2016 and 2015 as compared to other quarters.

Net Finance Income and Expense

	Three months ended December 31, 2016		Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016		Six months ended December 31, 2015	Change		Twelve months ended June 30, 2015	Change
Net financing expense paid	$ **4,573**	$	4,162	10%	$ **17,346**	$	9,260	87%	$	16,759	4%
Non-cash financing costs	**1,325**		1,108	20%	**5,323**		2,193	143%		11,048	(52%)
Net finance expense	$ **5,898**	$	5,270	12%	$ **22,669**	$	11,453	98%	$	27,807	(18%)

Net finance expense paid increased by 10% in the three ended December 31, 2016 compared to the same periods in 2015, due to an increase in LIBOR rate on which the BNP Senior Secured Term Loan interest is based on. Net finance expense paid increased by 87% in the year ended December 31, 2016 compared to the six months period ended December 31, 2015 due to the comparison being made between a twelve month period versus a six month period. Net finance expense paid increased by 4% in the year ended December 31, 2016 as compared to the year ended June 30, 2015 due to an increase in LIBOR rates on which the BNP Senior Secured Term Loan interest rate is based on, offset by a decrease in finance expense paid due to the $20 million pre-payment of the BNP Senior Secured Term Loan on September 30, 2015. The non-cash financing costs are related to the accretion of the decommissioning liabilities and the amortization of the debt upfront fees.

Commodity Contracts

During the year ended December 31, 2016, the Corporation entered into one financial oil collar under the following terms:

Period	Volume	Type	Price Range
Jul 2016 – Dec 2016	1,000 bbls/day	Financial WTI Oil Collar	$40.00 – $58.40

Gains and losses on commodity contracts recognized in comprehensive net income (loss) are summarized below:

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	**Twelve months ended December 31, 2016**	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Unrealized change in fair value	**$ (3)**	$ -	n/a	**$ -**	$ -	-	$ (38)	(100%)
Realized cash settlement	**-**	-	n/a	**-**	-	-	(182)	(100%)
Total (gain) loss	**$ (3)**	$ -	n/a	**$ -**	$ -	-	$ (220)	(100%)

Stock-Based Compensation Expense and Restricted Share Unit Expense

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	**Twelve months ended December 31, 2016**	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Stock-based compensation	**$ 1,002**	$ 2,267	(56%)	**$ 6,458**	$ 3,873	67%	$ 4,853	33%
Restricted share unit expense	**62**	68	(9%)	**3,189**	93	>999%	1,034	208%
Stock-based compensation expense and restricted share units	**$ 1,064**	$ 2,335	(54%)	**$ 9,647**	$ 3,966	143%	$ 5,887	64%

Stock-based compensation is a non-cash expense recognized as the fair value calculated on grant date amortized over the vesting period of each grant. The restricted share units expense is a non-cash expense recognized based on the fair value of units granted during the period.

Depletion and Depreciation Expense

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	**Twelve months ended December 31, 2016**	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Depletion and depreciation expense	**$ 6,193**	$ 13,906	(55%)	**$ 26,512**	$ 26,479	-	$ 61,262	(57%)
$/boe	**$ 3.82**	$ 16.78	(77%)	**$ 4.57**	$ 14.58	(69%)	$ 14.57	(69%)

Depletion and depreciation expense decreased 55% in the three months ended December 31, 2016 compared to 2015 primarily as a result of the decommissioning obligation asset change in estimate adjustment on Rancho Hermoso recorded as a reduction of depletion and depreciation expense. Depletion and depreciation expense in the year ended December 31, 2016 as compared to the six months ended December 31, 2015 is consistent, despite the comparison being a twelve month period versus a six month period, due to the decommissioning obligation asset adjustment mentioned above, as well as a lower depletable base for the year ended December 31, 2016 as a result of impairment expense booked in the six months ended December 31, 2015. Depletion and depreciation expense decreased 57% in the year ended December 31, 2016 compared to the year ended June 30, 2015, primarily due to a lower depletable base for the year ended December 31, 2016 as a result of impairment expenses booked in the six months ended December 31, 2015 and the year ended June 30, 2015.

Impairment on Development and Production Assets

	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Impairment on development and production assets	**$ 37,318**	$ 44,599	**$ 37,318**	$ 44,599	$ 72,057

Impairment tests carried out at December 31, 2016, December 31, 2015 and June 30, 2015 were based on fair value calculations, using pre-tax discount rates ranging from 10% to 15% and forward commodity price estimates. The impairment tests resulted in a write-down primarily related to the LLA-23 and Capella assets totalling $37.3 million (six months ended December 31, 2015 – $44.6 million; year ended June 30, 2015 – $72.1 million) during the year ended December 31, 2016. The Corporation's other fields were not affected.

Income Tax Expense

	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Current income tax (recovery) expense	**$ (6,256)**	$ 647	**$ 16,079**	$ 3,459	$ 7,671
Deferred income tax (recovery) expense	**(42,347)**	8,803	**(50,162)**	12,325	(204)
Income tax (recovery) expense	**$ (48,603)**	$ 9,450	**$ (34,083)**	$ 15,784	$ 7,467

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 40%. The Corporation continues to utilize and develop various tax planning strategies, including restructuring and transfer pricing amongst its jurisdictions to reduce its current and future income tax expenses. During the three months ended December 31, 2016, the Corporation recognized a current income tax recovery of $6.3 million as a result of executing its tax planning strategies. The Corporation recognized a deferred income tax recovery of $42.3 million during the three months ended December 31, 2016 mainly as a result of a) executing its tax planning strategies which allowed the Corporation to recognize deferred tax assets that could not be recognized in the previous year and b) the tax impact related to the impairment of the exploration and development assets.

Cash and Funds from Operations and Comprehensive Income (Loss)

	Three months ended December 31, 2016	Three months ended December 31, 2015	Change	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Change	Twelve months ended June 30, 2015	Change
Cash provided by operating activities	**$ 30,289**	$ 4,974	509%	**$ 73,577**	$ 19,276	282%	$ 64,445	14%
Per share – basic ($)	**$ 0.17**	$ 0.03	467%	**$ 0.44**	$ 0.14	214%	$ 0.58	(24%)
Per share – diluted ($)	**$ 0.17**	$ 0.03	467%	**$ 0.44**	$ 0.13	238%	$ 0.58	(24%)
Adjusted funds from operations (1)	**$ 41,979**	$ 8,473	395%	**$ 113,019**	$ 23,690	377%	$ 87,395	29%
Per share – basic ($)	**$ 0.24**	$ 0.05	380%	**$ 0.68**	$ 0.17	300%	0.79	(14%)
Per share – diluted ($)	**$ 0.24**	$ 0.05	380%	**$ 0.67**	$ 0.16	319%	0.78	(14%)
Comprehensive income (loss)	**$ 20,331**	$ (84,466)	n/a	**$ 23,638**	$ (103,495)	n/a	$ (106,022)	n/a
Per share – basic ($)	**0.12**	$ (0.54)	n/a	**$ 0.14**	$ (0.72)	n/a	$ (0.96)	n/a
Per share – diluted ($)	**0.12**	$ (0.54)	n/a	**$ 0.14**	$ (0.72)	n/a	$ (0.96)	n/a

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

Capital Expenditures

	Three months ended December 31, 2016	Three months ended December 31, 2015	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Drilling and completions	$ 16,553	$ 2,090	$ 35,864	$ 14,306	$ 97,320
Facilities, work overs and infrastructure	37,397	6,914	48,900	12,464	18,276
Land, seismic, communities and other	10,719	4,912	24,053	6,267	28,239
Non-cash costs and adjustments (2)	(6,003)	8,478	(12,320)	11,656	19,552
Property acquisitions	-	-	11,483	-	75,609
Dispositions and farm-outs	(28)	-	(50)	-	(21,654)
Net capital expenditures	58,638	22,394	107,930	44,693	217,342
Ecuador	1,053	473	2,294	4,254	25,766
Adjusted net capital expenditures (1)	$ 59,691	$ 22,867	$ 110,224	$ 48,947	$ 243,108
Net capital expenditures recorded as:					
Expenditures on exploration and evaluation assets	$ 12,062	$ 3,170	$ 36,510	$ 5,632	$ 73,183
Expenditures on property, plant and equipment	46,604	19,224	59,987	39,061	90,204
Property acquisition	-	-	11,483	-	75,609
Disposition and farm-outs	(28)	-	(50)	-	(21,654)
Net capital expenditures	$ 58,638	$ 22,394	$ 107,930	$ 44,693	$ 217,342

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Other non-cash costs include the non-cash adjustments related to changes in estimates of decommissioning liabilities

Capital expenditures for the three months ended December 31, 2016 primarily related to:

- Jobo 2 gas plant finance lease of $33 million, included under facility costs;
- Drilling and facilities costs at Esperanza;
- Drilling and facilities costs at VIM-5;
- Drilling costs at VMM-2;
- Facilities costs at LLA-23;
- Facilities costs related to the Ecuador IPC (accounted for under the equity method of accounting); and
- Other capitalized costs (capitalized G&A of $1.6 million and non-cash net write-down adjustments related to changes in estimates of decommissioning liabilities of $6 million)

LIQUIDITY AND CAPITAL RESOURCES

Capital Management

The Corporation's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain investor, creditor and market confidence. The Corporation manages its capital structure and makes adjustments in response to changes in economic conditions and the risk characteristics of the underlying assets. The Corporation considers its capital structure to include share capital, bank debt and working capital, defined as current assets less current liabilities, excluding the current portion of bank debt and any non-cash items. In order to maintain or adjust the capital structure, from time to time the Corporation may issue common shares or other securities, sell assets or adjust its capital spending to manage current and projected debt levels.

The Corporation monitors leverage and adjusts its capital structure based on its net debt level. Net debt is defined as the principal amount of its outstanding bank debt, less working capital, as defined above. In order to facilitate the management of its net debt, the Corporation prepares annual budgets, which are updated as necessary depending on varying factors including current and forecast crude oil prices, changes in capital structure, execution of the Corporation's business plan and general industry conditions. The annual budget is approved by the Board of Directors and updates are prepared and reviewed as required.

On August 2, 2016 and August 5, 2016, the Corporation completed the first and second tranche of private placement offerings of 9,687,670 and 1,800,000 common shares of the Corporation, respectively, issued at C$4.08 per common share for a total of C$46.9 million. The private placement offering further enhances the Corporation's liquidity and its ability to explore and develop its 100% operated gas assets for the remainder of 2016. Subsequent to December 31, 2016, the Corporation executed a new credit agreement to refinance its existing debt consisting of the BNP Senior Secured Term Loan and the Senior Notes, totaling $255 million as at December 31, 2016, into a single loan facility, with the following benefits: a) a lower the average interest rate, and b) extend the first amortization payment of the new term loan into 2019.

		December 31, 2016
Bank debt – principal	$	255,000
Working capital surplus		(64,899)
Net debt	**$**	**190,101**

Credit Facilities and Debt

Senior Secured Term Loan

On April 24, 2015, the Corporation entered into a credit agreement for a $200 million senior secured term loan with a syndicate of banks led by BNP Paribas ("BNP") ("BNP Senior Secured Term Loan"). The BNP Senior Secured Term Loan is scheduled to mature on September 30, 2019, with interest payable quarterly and principal repayable in eight equal quarterly installments starting on December 31, 2017, following an initial grace period. As such, $22.5 million of the BNP Senior Secured Term Loan principal, net of unamortized transaction costs, is classified as current and the remaining balance is classified as non-current as at December 31, 2016. The BNP Senior Secured Term Loan carries interest at LIBOR plus 4.75% and is secured by all of the material assets of the Corporation.

On September 30, 2015 the Corporation pre-paid $20 million on its BNP Senior Secured Term Loan, thus reducing the balance outstanding to $180 million. The carry value of the BNP Senior Secured Term Loan included $2.5 million of transaction costs netted against the principal amount as at December 31, 2016.

The BNP Senior Secured Term Loan includes various non-financial covenants relating to future acquisitions, indebtedness, operations, investments, capital expenditures and other standard operating business covenants. The BNP Senior Secured Term Loan also includes various financial covenants, including a maximum consolidated leverage ratio ("Consolidated Leverage Ratio") of 3.50:1.00, a minimum consolidated interest coverage ratio ("Consolidated Interest Coverage Ratio") of 2.50:1.00 and a minimum consolidated current assets to consolidated current liabilities ratio ("Consolidated Current Assets to Consolidated Current Liabilities Ratio") of 1.00:1.00.

The Consolidated Leverage Ratio is calculated on a quarterly basis as consolidated total debt ("Consolidated Total Debt") divided by consolidated EBITDAX ("Consolidated EBITDAX"). The maximum allowable Consolidated Leverage Ratio is 3.50:1.00. Consolidated Total Debt includes the principal amount of all indebtedness, which currently includes bank debt and finance lease obligation; additionally, restricted cash maintained in the debt service reserve account related to the BNP Senior Secured Term Loan is deductible against Consolidated Total Debt. Consolidated EBITDAX is calculated on a rolling 12-month basis and is defined as consolidated net income adjusted for interest, income taxes, depreciation, depletion, amortization, exploration expenses, equity profit (loss) and other similar non-recurring or non-cash charges. Consolidated EBITDAX is further adjusted for the contribution to adjusted funds from operations, before taxes, of the results of the Ecuador IPC. The purpose of including this last amount is to capture the funds from operations of the Corporation's joint venture in Ecuador into the calculation as it is accounted for on an equity consolidation basis in the Corporation's consolidated financial statements.

Consolidated Total Debt and Consolidated EBITDAX are calculated as follows:

Consolidated Total Debt		**December 31, 2016**
Bank debt (current and long-term) – principal	$	255,000
Finance lease obligation		32,762
Debt service reserve account balance		(3,000)
Consolidated Total Debt	$	**284,762**

Consolidated EBITDAX	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Rolling
Consolidated net income (loss)	461	11,245	(8,399)	20,339	23,646
(+) Interest expense	5,361	5,360	5,531	5,873	22,125
(+/-) Income taxes (recovery) expense	(745)	7,662	7,603	(48,603)	(34,083)
(+) Wealth taxes	850	285	-	-	1,135
(+) Depletion and depreciation	5,834	3,671	10,814	6,193	26,512
(+) Exploration expenses	40	99	14,583	2,808	17,530
(+/-) Equity (income) loss	(294)	(718)	(387)	1,779	380
(+/-) Other non-cash expenses (income) and non-recurring items	4,000	1,807	5,372	41,834	53,013
(+) Contribution of Ecuador IPC	6,300	6,464	6,459	5,976	25,199
Consolidated EBITDAX	21,807	35,875	41,576	36,199	135,457

Consolidated Leverage Ratio		December 31, 2016
Consolidated Total Debt	$	284,762
Consolidated EBITDAX		135,457
Consolidated Leverage Ratio		2.10

The Consolidated Interest Coverage Ratio is calculated on a quarterly basis as Consolidated EBITDAX divided by consolidated interest expense ("Consolidated Interest Expense"). The minimum Consolidated Interest Coverage Ratio required is 2.50:1.00. Consolidated EBITDAX is calculated on a rolling 12-month basis as described in the above paragraph. Consolidated Interest Expense is calculated on a rolling 12-month basis and includes interest expense and capitalized interest, net of interest income, and excludes any non-cash interest charges.

Consolidated Interest Coverage Ratio		December 31, 2016
Interest expense	$	19,715
Interest income		(2,369)
Consolidated Interest Expense	$	17,346
Consolidated EBITDAX	$	135,457
Consolidated Interest Coverage Ratio		7.81

The Consolidated Current Assets to Consolidated Current Liabilities Ratio is calculated on a quarterly basis as consolidated current assets divided by consolidated current liabilities, excluding the current portion of any long-term indebtedness and any non-cash current assets and non-cash current liabilities. The minimum Consolidated Current Assets to Consolidated Current Liabilities Ratio required is 1.00:1.00. As at December 31, 2016, the Consolidated Current Assets to Consolidated Current Liabilities Ratio was 2.11:1.00.

The Corporation was in compliance with its covenants as at December 31, 2016.

Senior Notes

On October 29, 2014, the Corporation entered into the $100 million unsecured floating rate senior note indenture agreement with Apollo Investment Corporation ("Senior Notes"), with $50 million drawn and funded on October 29, 2014, $25 million drawn and funded on April 2, 2015, and a further $25 million committed and available to be drawn at any time up to April 27, 2016 at the sole discretion of the Corporation, which was not exercised by the Corporation. The Senior Notes are scheduled to mature in full on December 31, 2019 and carry interest at LIBOR plus 8.5% per annum (subject to a LIBOR floor of 1.00%), payable quarterly. The Senior Notes may be repaid at any time prior to maturity and are subject to customary financial, performance and legal covenants which are consistent with the covenants under the BNP Senior Secured Term Loan. Standby fees on the undrawn portion of the Senior Notes are calculated at 1% per annum. The carrying value of the Senior Notes included $1.9 million of transaction costs netted against the principal amount as at December 31, 2016.

2017 Senior Secured Term Loan

Subsequent to December 31, 2016, the Corporation entered into a credit agreement for $265 million senior secured term loan with a syndicate of banks led by Credit Suisse ("2017 Senior Secured Term Loan"). The 2017 Senior Secured Term Loan will mature on March 20, 2022, with interest payable quarterly and principal repayable in 13 equal quarterly installments starting March 20, 2019, following more than two years of initial grace period. The 2017 Senior Secured Term Loan carries interest at LIBOR plus 5.5% and is secured by all of the material assets of the Corporation. Proceeds from the 2017 Senior Secured Term Loan was used for repayment of the principal in the amount of $255 million including $180 million of the BNP Senior Secured Term Loan and $75 million of Senior Notes, plus accrued interest and costs of the transaction. Remaining proceeds from the 2017 Senior Secured Term Loan were made available for other general corporate purposes.

The 2017 Senior Secured Term Loan includes various non-financial and financial covenants including a maximum Consolidated Leverage Ratio of 3.00:1.00, a minimum Consolidated Interest Coverage Ratio of 3.50:1.00 and minimum consolidated current assets to Consolidated Current Assets to Consolidated Current Liabilities Ratio of 1.00:1.00. In addition, the Corporation has a requirement under the 2017 Senior Secured Term Loan agreement to hedge LIBOR.

Other Colombian Credit Facilities

The Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $61.7 million (COP$ 185 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. The facilities were undrawn as at and during the year ended December 31, 2016.

Letters of Credit

At December 31, 2016, the Corporation had letters of credit outstanding totaling $65.1 million to guarantee work commitments on exploration blocks and to guarantee other contractual commitments. The total of these letters of credit, net of amounts counter-guaranteed by other financial institutions, reduce the amounts available under the Colombian revolving lines of credit by $42.5 million to $19.2 million at December 31, 2016.

Share Capital

At March 23, 2017, the Corporation had 174.3 million common shares, 15.1 million stock options, and 1.8 million cash-settled restricted share units outstanding.

Contractual Obligations

The following table provides a summary of the Corporation's cash requirements to meet its financial liabilities and contractual obligations existing at December 31, 2016:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	$ 22,500	$ 232,500	-	$ 255,000
Finance lease obligation – undiscounted	8,219	17,979	19,139	45,337
Trade and other payables	32,438	-	-	32,438
Crude oil payable in kind	646	-	-	646
Taxes payable	15,195	-	-	15,195
Deferred income	3,991	-	3,731	7,722
Other long term obligations	-	-	3,328	3,328
Restricted share units	2,181	56	-	2,237
Exploration and production contracts	50,166	51,952	-	102,118
Jobo facility operating contract	3,250	7,072	7,569	17,891
Liquid natural gas processing contract	706	5,651	9,943	16,300
Office leases	1,291	1,566	1,277	4,135

Exploration and Production Contracts

The Corporation has entered into a number of exploration contracts in Colombia which require the Corporation to fulfill work program commitments and to issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at December 31, 2016 of $106 million and has issued $65.1 million in financial guarantees related thereto. These commitments are planned to be satisfied by means of seismic work, exploration drilling and farm-outs.

Oleoducto Bicentenario de Colombia ("OBC") Pipeline

The Corporation owns a 0.5% interest in OBC, which owns a pipeline system that will link Llanos basin oil production to the Cano Limon oil pipeline system. Under the terms of the OBC agreement, the Corporation may be required to provide financial support or guarantees for its proportionate equity interest in any future debt financings undertaken by OBC. The Corporation has also entered into ship-or-pay arrangements for 550 barrels of oil per day at $8.54 / barrel with OBC to guarantee its pipeline revenue.

Ecuador Incremental Production Contract

In addition to the commitments described above, the Corporation has a non-operated 25% equity participation interest in a joint-venture consortium which in 2012 was awarded an incremental production contract for the Libertador and Atacapi mature oil fields in Ecuador. The consortium plans to incur project expenditures estimated for a total of $397 million ($107.6 million net to the Corporation) over the 15 year term of the contract. As at December 31, 2016, the Corporation had incurred $85.3 million of expenditures in connection with its Ecuador IPC commitment.

OUTLOOK

2016 saw the emergence of Canacol Energy Ltd. as a premier gas producer in Colombia.

During 2016, the Corporation had many operational and financial accomplishments:

- The drilling and completion of the Oboe-1 exploration well and its combined test results of 66 MMscfpd in March 2016.
- The completion of the Promigas pipeline and the Promisol Jobo gas plant upgrade in April 2016, which allowed Canacol to increase gas production to 90 MMscfpd. Canacol's total current gas processing capability is 200 MMscfpd.
- The drilling and completion of the Nispero-1 exploration well and its test result of 28 MMscfpd in August 2016.
- The completion of the first and second tranche of private placement offerings of 9,687,670 and 1,800,000 common shares of the Corporation, respectively, issued at C$4.08 per common share for a total of C$46.9 million in August 2016.
- The drilling and completion of the Trombon-1 exploration well and its test result of 26 MMscfpd in October 2016.
- The drilling and completion of the Nelson-6 exploration well and its test result of 23 MMscfpd in November 2016.
- The initiation of a private pipeline venture in November, 2016 that will deliver 40 MMscfpd of new gas production to new and existing customers located on the Caribbean coast in December 2017, thereby increasing the Corporation's transportation capacity from its current 90 MMscfpd to 130 MMscfpd upon completion.
- The execution of the agreement with Promigas in November 2016 to expand the existing gas distribution network currently used by the Corporation to accommodate an additional 100 MMscfpd of new gas transportation and sales, thereby increasing the Corporation's transportation capacity to 230 MMscfpd in December 2018.
- The drilling and completion of the Clarinete-3 development well and its test result of 18 MMscfpd in December 2016.
- The Nelson-5 Porquero recompletion and its test result of 13 MMscfpd in December 2016.
- Proved Developed Producing "PDP" reserves and deemed volumes increased by 49% since December 31, 2015, to total 42.4 million barrels of oil equivalent ("MMboe") at December 31, 2016
- Total Proved + Probable "2P" reserves and deemed volumes totaled 84.6 MMboe at December 31, 2016, with a before tax value discounted at 10% of $1.3 billion, representing CAD $8.79 per share
- Achieved 1P reserve replacement of 166% and 2P reserve replacement of 194% based on calendar 2016 gross reserve and deemed volume additions of 9.3 MMboe and 11 MMboe, respectively
- Achieved 2P finding and development costs ("F&D") of $4.71/boe for its gas assets and $5.31/boe as a corporate total for calendar 2016
- Achieved 2P F&D of $2.52/boe for its gas assets and $3.48/boe as a corporate total for the two year period ending December 31, 2016
- Recorded 2P finding, development and acquisition costs ("FD&A") of $5.04/boe for its gas assets and $5.66/boe as a corporate total for calendar 2016
- Recorded a 2P reserves life index ("RLI") of 13 years based on annualized fourth quarter 2016 production of 17,778 boepd

On February 16, 2017, the Corporation announced that it had closed its 2017 $265 million senior secured term loan led by Credit Suisse. This facility replaced the Corporation's existing two facilities with BNP Paribas and Apollo Investment Corporation and will offer the following benefits: 1) defers amortization payments until March 2019, allowing the Corporation to dedicate capital to high netback production related projects instead of debt service; 2) reduces the total annual interest costs as compared to the combined BNP Facility and Apollo Notes by approximately 1.1% and, 3) harmonizes compliance and administrative deliverables under one facility. Having achieved this financial flexibility, for 2017, management's primary goals are to 1) achieve a gas production rate of 130 MMscfpd by December 1, 2017 via the construction of a new private gas pipeline, 2) drill three gas exploration wells to continue to build the Corporations gas reserves base at industry leading F&D costs, and 3) drill two oil exploration wells to increase oil production and satisfy exploration commitments to the ANH.

With respect to the new private gas pipeline, a Special Purpose Vehicle ("SPV") has been formed to build and operate a six inch pipeline that will transport 40 MMscfpd of gas from the Corporation's Jobo gas processing facility to Sincelejo / Bremen approximately 80 kilometers to the north, where the private pipeline will connect to the Promigas operated pipeline that ships gas to Cartagena. Canacol has executed a ten year take-or-pay contract for 40 MMscfpd of gas at contractual terms comparable to the Corporation's current US dollar denominated gas sale contracts. A bank has been retained to raise the $60 million that the SPV will require to complete the pipeline outside of Canacol. In the meantime, the SPV is acquiring all of the right of ways required for the pipeline, and is tendering all of the major contracts which would include tubulars and compression. The Corporation anticipates that the pipeline will be in operation on December 1, 2017. The productive capacity of the Corporation's currently producing wells is approximately 195 MMscfpd, and that of the Corporation's gas processing facilities approximately 200 MMscfpd.

Canacol has also spud the Canahuate-1 gas exploration well and the Pumara-1 oil exploration well. The Canahuate-1 exploration well, located on the Esperanza E&P Contract (100% operated working interest), was spud on March 24, 2017. The Canahuate-1 well is located approximately three kilometers ("kms") north of the Corporation's Jobo gas processing facility and is targeting gas bearing sandstones within the proven producing Cienaga de Oro reservoir. Over the past three years, six of the seven exploration wells drilled by the Corporation on its gas blocks, including the Esperanza E&P contract, have resulted in commercial gas discoveries. The Canahuate-1 well is expected to take approximately six weeks to drill and test.

Canacol also maintains a large inventory of light oil drill ready production and exploration opportunities. The Corporation will spud the Pumara-1 exploration well on the LLA-23 E&P Contract (100% operated working interest) on March 31, 2017. The Pumara-1 exploration well is located three kms north of the Labrador field and is targeting light oil bearing reservoirs within the proven producing C7, Mirador, Gacheta and Ubaque reservoirs. Over the past four years, five of the six exploration wells drilled by the Corporation on the LLA-23 contract have resulted in commercial producing light oil discoveries. The Pumara-1 well is expected to take approximately five weeks to drill and test, and if successful, it will be placed immediately on permanent production via the Corporation's oil processing facilities located at Pointer.

The Corporation anticipates releasing an update on its Mono Capuchino-1 exploration well on March 28, 2017 and its 2017 guidance during the week of April 3, 2017.

SUMMARY OF QUARTERLY RESULTS

	2016				2015			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
Petroleum and natural gas revenues, net of royalties	**41,967**	44,392	38,926	22,700	17,402	21,958	27,297	26,429
Adjusted petroleum and natural gas revenues, net of royalties(1)	**47,943**	50,851	45,390	29,000	24,883	29,899	33,892	32,811
Cash provided by (used in) operating activities	**30,289**	22,275	13,764	7,249	4,974	14,302	(10,905)	(2,011)
Per share – basic	**0.17**	0.13	0.09	0.05	0.03	0.11	(0.09)	(0.02)
Per share – diluted	**0.17**	0.13	0.08	0.05	0.03	0.11	(0.09)	(0.02)
Adjusted funds from operations (1)	**41,979**	30,719	26,870	13,451	8,473	15,218	16,359	10,922
Per share – basic (1)	**0.24**	0.18	0.17	0.08	0.05	0.12	0.14	0.10
Per share – diluted (1)	**0.24**	0.18	0.16	0.08	0.05	0.12	0.14	0.10
Comprehensive income (loss)	**20,331**	(8,399)	11,245	461	(84,466)	(19,029)	(58,524)	(15,638)
Per share – basic	**0.12**	(0.05)	0.07	-	(0.54)	(0.15)	(0.50)	(0.14)
Per share – diluted	**0.12**	(0.05)	0.07	-	(0.54)	(0.15)	(0.50)	(0.14)
Capital expenditures, net	**58,638**	28,698	5,046	15,548	22,394	22,299	25,310	62,482
Adjusted capital expenditures, net, including capital expenditures related to the Ecuador IPC (1)	**59,691**	29,208	5,376	15,949	22,867	26,080	27,268	68,778
Operations (boepd)								
Petroleum and natural gas **production**, before royalties								
Petroleum (2)	**3,616**	3,892	4,018	4,526	5,523	6,983	6,007	7,448
Natural gas	**14,112**	14,740	12,405	6,407	3,541	3,472	3,954	3,502
Total (2)	**17,728**	18,632	16,423	10,933	9,064	10,455	9,961	10,950
Petroleum and natural gas **sales**, before royalties								
Petroleum (2)	**3,657**	3,801	4,045	4,578	5,468	7,272	6,192	7,636
Natural gas	**13,986**	14,621	12,331	6,329	3,542	3,455	4,064	3,462
Total (2)	**17,643**	18,422	16,376	10,907	9,010	10,727	10,256	11,098
Realized contractual sales, before royalties								
Natural gas	**14,653**	15,107	12,972	6,642	3,891	3,455	4,064	3,462
Colombia oil	**2,026**	2,090	2,294	2,856	3,390	5,116	4,433	5,932
Ecuador tariff oil (2)	**1,631**	1,711	1,751	1,722	2,078	2,156	1,759	1,704
Total (2)	**18,310**	18,908	17,017	11,220	9,359	10,727	10,256	11,098

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Includes tariff oil production related to the Ecuador IPC.

SUPPLEMENTAL FINANCIAL INFORMATION

	December 31, 2016	December 31, 2015	June 30, 2015
Total assets	$ 787,508	$ 668,349	$ 669,742
Total bank debt	250,638	248,228	267,023

	Twelve months ended December 31, 2016	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Petroleum and natural gas revenues, net of royalties	$ 147,985	$ 39,360	$ 149,047
Comprehensive income (loss)	23,638	(103,495)	(106,022)
Per share – basic ($)	0.14	(0.72)	(0.96)
Per share – diluted ($)	0.14	(0.72)	(0.96)

RISKS AND UNCERTAINTIES

The Corporation is subject to several risk factors including, but not limited to: the volatility of oil and natural gas prices; foreign exchange and currency risks; general risks related to foreign operations such as political, economic, regulatory and other uncertainties as they relate to both foreign investment policies and energy policies; governments exercising from time to time significant influence on the economy to control inflation; developing environmental regulations in foreign jurisdictions; discovery of new oil and natural gas reserves; concentration of oil sales receipts with a few major customers; substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the long-term for which additional financings may be required to implement the Corporation's business plan. Although periodic volatility of financial and capital markets may severely limit access to capital, the Corporation has been able to successfully attract capital in the past.

The Corporation is exposed to foreign exchange and currency risk as a result of fluctuations in exchange rates through its cash deposits and investments denominated in the Colombian peso and the Canadian dollar.

Most of the Corporation's revenues and funds from financing activities are expected to be received in reference to United States dollar ("US dollar") denominated prices while a portion of its operating, capital, and general and administrative costs are denominated in Colombian Pesos and Canadian dollars. The Colombian Peso has seen significant variation against the US dollar in the past and it continues to have significant daily fluctuations. The Corporation has not entered into any currency derivatives in order to reduce its exposure to fluctuations that the US dollar may incur.

The Corporation is exposed to interest rate risk on certain variable interest rate debt instruments, to the extent they are drawn. The remainder of the Corporation's financial assets and liabilities are not exposed to interest rate risk. The Corporation had no interest rate swap or financial contracts in place as at or during the year ended December 31, 2016.

Fluctuations in energy prices will not only impact revenues of the Corporation but may also impact the Corporation's ability to raise capital. Commodity prices for crude oil are impacted by world economic events that dictate the levels of supply and demand. From time to time the Corporation may attempt to mitigate commodity price risk through the use of financial derivatives. The Corporation's policy is to only enter into commodity contracts considered appropriate to a maximum of 50% of forecasted production volumes. During the year ended December 31, 2016, the Corporation entered into one financial oil collar under the following terms:

Period	Volume	Type	Price Range
Jul 2016 – Dec 2016	1,000 bbls/day	Financial WTI Oil Collar	$40.00 – $58.40

The Corporation's policy is to enter into agreements with customers that are well established and well-financed entities in the oil and gas industry such that the level of risk associated with one or more of its customers facing financial difficulties are mitigated while balancing factors of economic dependence with profit maximization. To date, the Corporation has not experienced any material credit loss in the collection of trade accounts receivable.

The Corporation attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The Corporation also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

A more comprehensive discussion of risks and uncertainties is contained in the Corporation's Annual Information Form for the year ended December 31, 2016 as filed on SEDAR and hereby incorporated by reference.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgements, assumptions and estimates in the preparation of the financial statements. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and the Corporation's significant accounting policies can be found in the notes to the financial statements.

CHANGES IN ACCOUNTING POLICIES

The Corporation is currently reviewing a number of new and revised IFRSs that have been issued but are not yet effective. Detailed discussions of new accounting policies that may affect the Corporation are provided in the financial statements of the Corporation as at and for the year ended December 31, 2016.

REGULATORY POLICIES

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("DC&P") are designed to provide reasonable assurance that all material information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure and that information required to be disclosed by the issuer under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), along with other members of management, have designed, or caused to be designed under the CEO and CFO's supervision, DC&P and have assessed the design and operating effectiveness of the Corporation's DC&P as at December 31, 2016. Based on this assessment, it was concluded that the design and operation of the Corporation's DC&P are effective as at December 31, 2016.

Internal Controls over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate Internal Control over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS. The Corporation's CEO and CFO, with support of management have assessed the design and operating effectiveness of the Corporation's ICFR as at December 31, 2016 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, it was concluded that the design and operation of the Corporation's ICFR are effective as at December 31, 2016.

During the quarter ended December 31, 2016, there has been no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Limitations of Controls and Procedures

The Corporation's management, including its CEO and CFO, believe that any DC&P or ICFR, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, they cannot provide absolute assurance that all control issues and instances of fraud, if any, within the Corporation have been prevented or detected. These inherent limitations include the realities that judgements in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Accordingly, because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and not be detected. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.